Optimum Tubing Size Prediction for Vertical Multiphase flow in Niger Delta Wells

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Abstract – The Prediction and Selection of Optimum Tubing Size (OTS) is mandatory and important for optimum production from an oil and gas well. The size of tubing is one of the important parameters affecting the pressure gradient on a multiphase fluid flow condition. This paper presents a software {Optimum Tubing Size Predictor (OTSP)} developed and used to predict the OTS for tubing sizes within the range of 2 3/8'' to 6'' on vertical multiphase flow in the Niger Delta. Vertical models of category C were used and an analytical model was generated after fitting hundred wells data .The output shows that Total Pressure Gradient (TPG) expectedly decreases with an increase in tubing size for a particular well but after the OTS, increases with increase in the tubing sizes with a change in flow regime. For the wells used in this study, the OTS was 3 ½'' with a TPG of 26.1373 psf/ft and 6'' with a TPG of 27.3338 psf/ft for Aziz, Govier and Fogarasi model while the OTS was 4'' with a TPG of 27.5722 psf/ft and 5'' with a TPG of 30.307 psf/ft for Orkiszewski model. Similarly, the OTS was 6'' with a TPG of 28.8763 psf/ft and 6'' with a TPG of 27.1252 psf/ft for the new model.

Index Terms – Data fitting, Optimum Tubing Size, Total Pressure Gradient, Prediction, Vertical Multiphase flow

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1 INTRODUCTION

Tubing is one of the important component parts in the production system of a flowing well and is the main channel for oil and gas production. The selection and determination of tubing sizes are critical decision making phase during well completion process by the production engineer. The traditional practice is that the rational tubing size be selected and determined using the sensitivity analysis of tubing sizes, which is based on the nodal analysis at the flowing production stage [1]. Tubing size, a function of pressure gradient of a vertical multiphase flow on which the production capacity of a well is based should be examined with different approach before selection. Undersized tubing will limit the production rate due to the increased friction resistance caused by excessive flow velocity and contrarily, oversized tubing may have a low flow velocity which may lead to excessive liquid phase loss due to slippage effect. Therefore, only by selecting an appropriate tubing size can the friction resistance and liquid phase loss due to slippage effect be in the optimum state. Multiphase vertical flow of fluid in the tubing is a complex phenomenon and several models (Empirical and Mechanistic) have been developed over the years for predicting Pressure gradient, liquid holdup and flow pattern. Pressure gradient correlation for a vertical multiphase flow is an important factor considered for the concurrent flow of oil and gas through the production tubing. Duns and Ros [2], Orkiszewski [3], Aziz *et al*. [4], Beggs and Brill [5], Chierrci *et al*.[6] and Mukherjee and Brill [7] developed the most widely used correlations for vertical multiphase flow. Pucknell *et al*. [8] in their study, concludes that none of the traditional multiphase flow correlations works well across the full range of conditions encountered in oil and gas fields. Bello *et al*. [9] in their study described multiphase fluid flow

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as a transient phenomenon since the flow regime changes from dispersed bubble to slug, plug, annular and stratified flow depending on the fluid properties, flow rates, tubing size and pressure drop . Recently, Omon *et al*. [10] developed a model for liquid holdup, pressure drop gradient with DataFit and estimated the bottom hole flowing pressure for single and multiphase system, the liquid holdup and the flow pattern of a vertical well from existing correlations incorporated into multiflow software developed in their study.

Several correlations have been developed for estimating pressure gradient for a vertical multiphase flow but none of these correlations is generally accepted to give accurate results due to the complex nature of multiphase flow and since they are restricted by their range of applicability. Thus, this work intends to develop a computer model for predicting optimum tubing size and an analytical model with liquid and gas density, liquid and gas flow rate and tubing size as an independent variable for estimating total pressure gradient for a vertical multiphase flow.

2 METHODOLOGY

2.1 Mathematical model

A steady state mechanical energy balance (pressure gradient) for one pounce mass of fluid may be expressed as;

$$\frac{dP}{dL} = \frac{g}{g_c}\rho sin\theta + \frac{f\rho v^2}{2g_c d} + \frac{\rho v dv}{g_c dL} \tag{1}$$

Thus the steady state pressure gradient can be considered to be composed of three distinct components:

$$\left[\frac{dP}{dL}\right]_T = \left[\frac{dP}{dL}\right]_{el} + \left[\frac{dP}{dL}\right]_{fric} + \left[\frac{dP}{dL}\right]_{acc} \tag{2}$$

If acceleration component is neglected, vertical tubing system and slip is considered, the steady state pressure gradient reduces to:

$$\frac{dP}{dL} = \frac{g}{g_c}\rho_{tp} + \frac{f\rho_{tp}V_m^2}{2g_c d} \tag{3}$$

Where two-phase density:

$$\rho_{tp} = \rho_L H_L + \rho_g H_g \tag{4}$$

Mixture velocity is given as:

$$V_m = V_{SL} + V_{Sg} \tag{5}$$

$$V_m = \frac{4[q_L + q_g]}{\pi d^2} \tag{6}$$

Substituting equation (6) into equation (3):

$$\frac{dP}{dL} = \frac{g}{g_c}\rho_{tp} + \frac{f\rho_{tp}}{2g_c d}\left[\frac{4[q_L+q_g]}{\pi d^2}\right]^2 \tag{7}$$

$$\frac{dP}{dL} = \frac{g}{g_c}\rho_{tp} + \frac{16f\rho_{tp}(q_L+q_g)^2}{2\pi^2 g_c d^5} \tag{8}$$

$$\frac{dP}{dL} = \frac{g}{g_c}\rho_{tp} + \left(\frac{8}{\pi^2}\right)\left[\frac{f\rho_{tp}}{g_c d^5}\right]\left[q_L + q_g\right]^2 \tag{9}$$

$$Let \quad C_1 = \frac{8}{\pi^2} \tag{10}$$

And total flow rates:

$$q_m = q_L + q_g \tag{11}$$

The total pressure gradient becomes:

$$\frac{dP}{dL} = \frac{g}{g_c}\rho_{tp} + C_1\left[\frac{f\rho_{tp}q_m^2}{g_c d^5}\right] \tag{12}$$

$$\frac{dP}{dL} = TPG = f(\rho_L, \rho_g, q_L, q_g, d) \tag{13}$$

Field data such as TPG, Liquid density (ρ_L), Gas density (ρ_g), Liquid flow rate (q_L), Gas flow rate (q_g) and tubing sizes (d) were obtained from Niger delta wells.

The data were used to develop a model for TPG as a function of Liquid and gas density, liquid and gas flow rate and the tubing sizes with data fit tool. The best model was selected out of

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several models generated after 100 data points were fitted.

New model:

$$\frac{dP}{dL} = TPG = \exp\left(A\rho_L + B\rho_g + Cq_L + Dq_g + Ed + F\right) \quad (14)$$

Where; ρ_L, ρ_g, q_L, q_g, d are the liquid density, gas density, liquid flow rate, gas flow rate and tubing sizes respectively. Their ranges are presented in Table 3 of the Appendix.The Coefficients A to F and the key statistical parameters are presented in Table 1 and 2 of the Appendix.

2.2 Development and Description of Optimum Tubing Size Predictor (OTSP)

OTSP was developed using Microsoft Visual Basic.Net. Development of OTSP was based on the widely used vertical multiphase flow models (Aziz *et al* and Orkiszewski), new model and fluid properties correlation. OTSP is a package designed to help Production engineers understand multiphase flow behavior in production tubing and to select the appropriate tubing size for wells. The tool determines two-phase density, superficial velocity of liquid and gas, pressure gradient due to elevation, pressure gradient due to friction, total pressure gradient, total pressure drop, flow regime, liquid holdup and Optimum tubing size. The tool is broken down into various components: input and output data section, optimum tubing size interface and model comparison interface as shown in Fig. 1, Fig.2 and Fig. 3; The task execution process for the OTSP is in Fig.4

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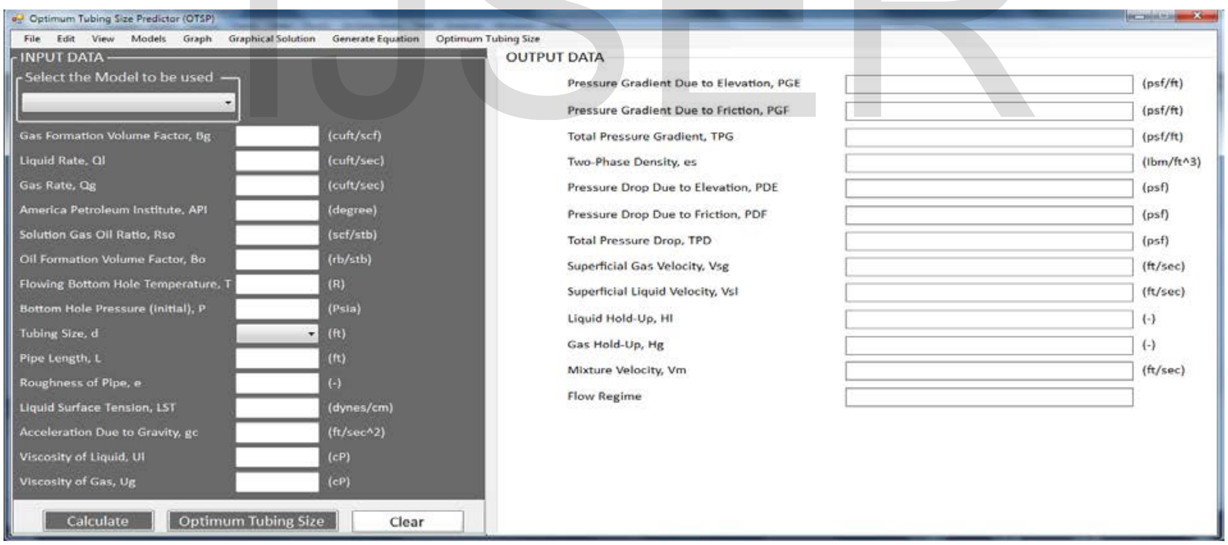

Fig. 1 Input and output section

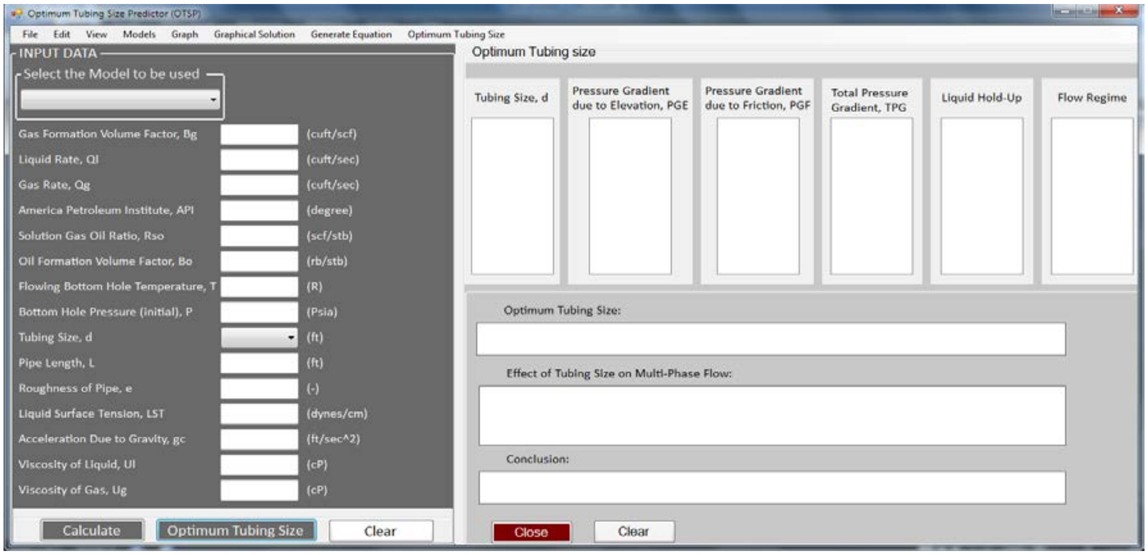

Fig. 2 Optimum Tubing Size Interface

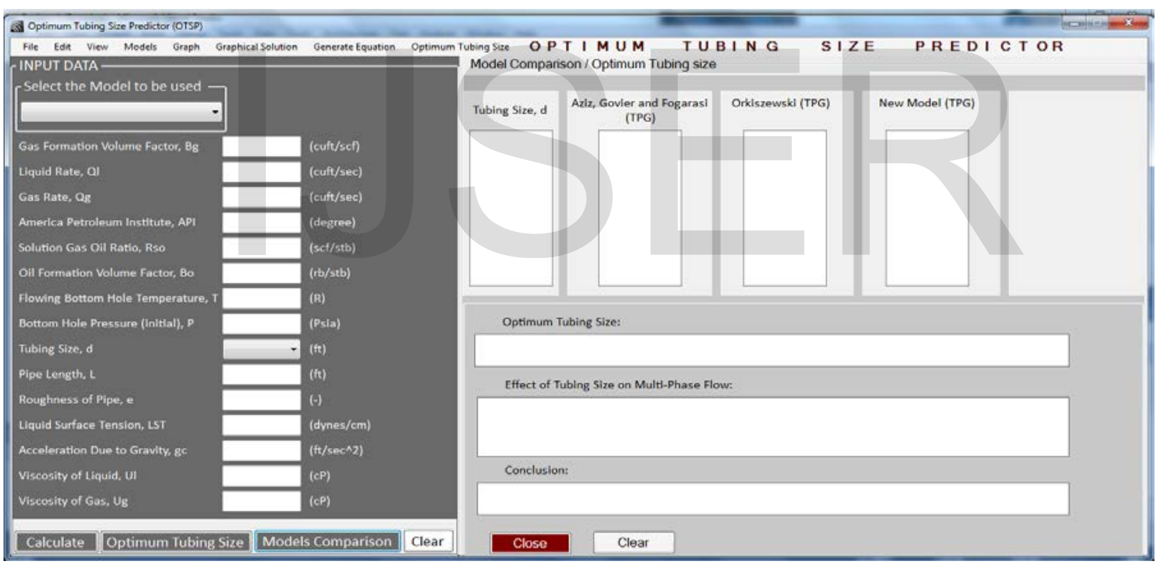

Fig. 3 Model Comparison Interface

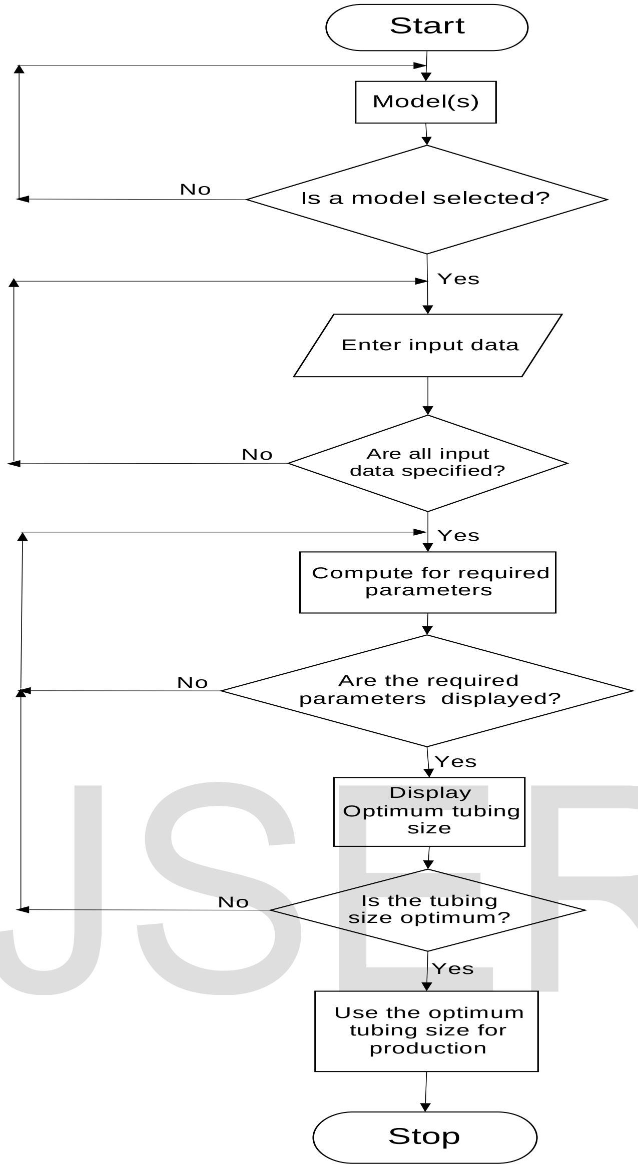

Fig. 4 OTSP Algorithm

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3 RESULTS AND DISCUSSION

3.1 New model for total pressure gradient

Equation (14) shows the new model developed for TPG for Niger Delta wells.

3.2 Results of the models

The total pressure gradient model developed in this study as a function of liquid and gas density, liquid and gas flow rate and tubing size in equation (14) were selected as the best model from the various models generated by datafit tool. The total pressure gradient model developed were compared with the existing vertical models and the TPG obtained range between 26.1373 psf/ft and 36.399 psf/ft for Aziz, Govier and Fogarasi model, 27.5722 psf/ft and 34.6132 psf/ft for Orkiszewski model and 28.8763 psf/ft and 31.5336 psf/ft for the new model for tubing sizes within the range of 6′′and 2 3/8′′for well 1. Similarly, the TPG obtained range between 27.3338 psf/ft and 37.2067 psf/ft for Aziz, Govier and Fogarasi model, 30.307 psf/ft and 153.8711psf/ft for Orkiszewski model and 27.1251 psf/ft and 29.6212 psf/ft for the new model for tubing sizes within the range of 6″ and 2 3/8″ for well 2.

3.3 Optimum tubing size (OTS) selection

The tool (OTSP) predicted 3 ½′′ as the OTS highlighted with a TPG of 26.1373 psf/ft for well 1 with Aziz, Govier and Fogarasi model and 6′′as the OTS highlighted with a TPG of 27.1252 psf/ft for well 2 with new model as the best model out of tubing size ranging 2 3/8′′, 2 7/8′′, 3′′, 3 ½′′, 4′′, 4 ½′′, 5′′, 5 ½′′, 6′′ as presented in Fig.5 and Fig.6.

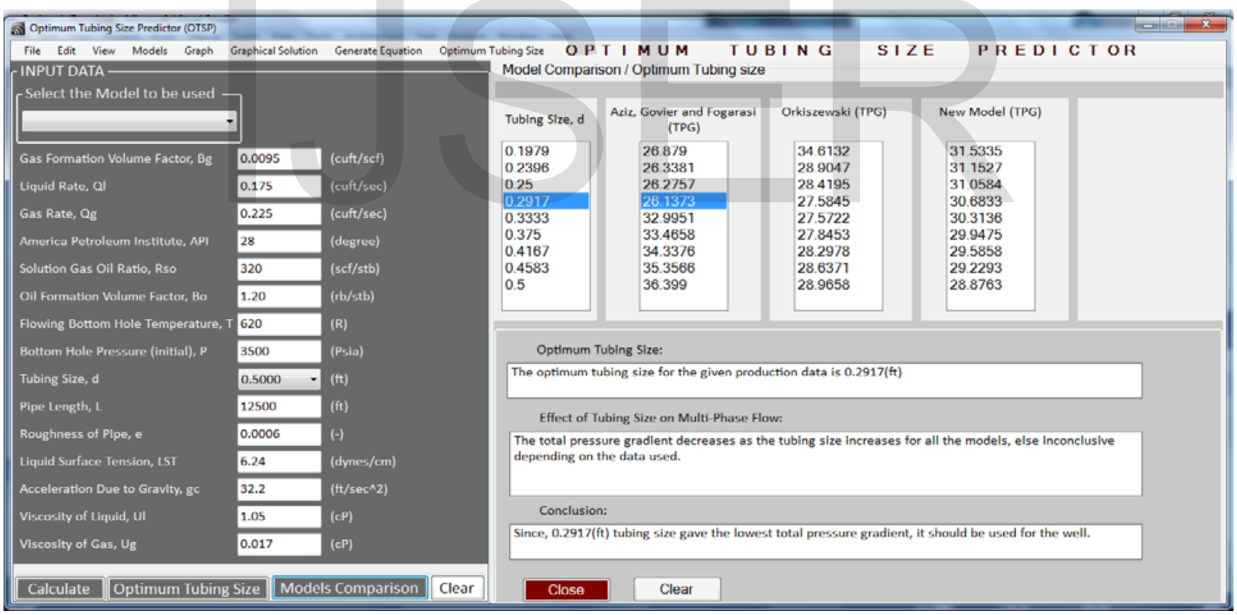

Fig. 5 OTS for well 1

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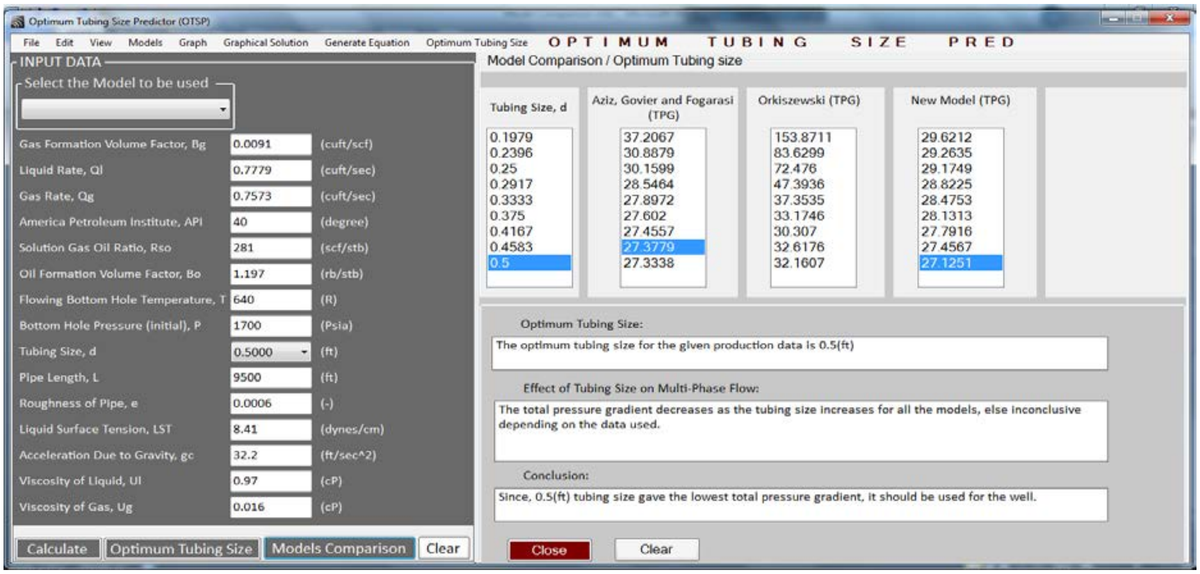

Fig. 6 OTS for well 2

3.4 Effects of tubing size on total pressure gradient (TPG)

Increase in tubing sizes decreases the total pressure gradient for both the new model and Orkiszewski model while Aziz et al model was the opposite for well 1 as presented in Fig.7. For well 2, the new model and Aziz et al have similar trend with no clear difference of increase in tubing size decreasing the pressure gradient while increase in tubing sizes decreases the total pressure gradient for Orkiszewski model as shown in Fig. 8

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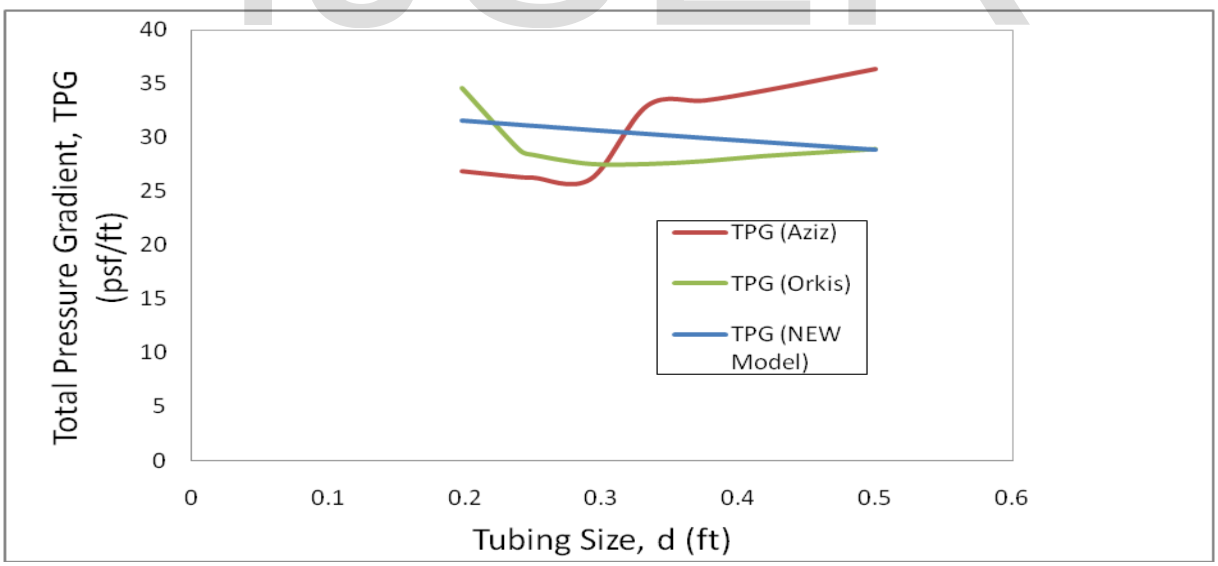

Figure 7: Total pressure gradient (TPG) at different tubing sizes for all models for well 1

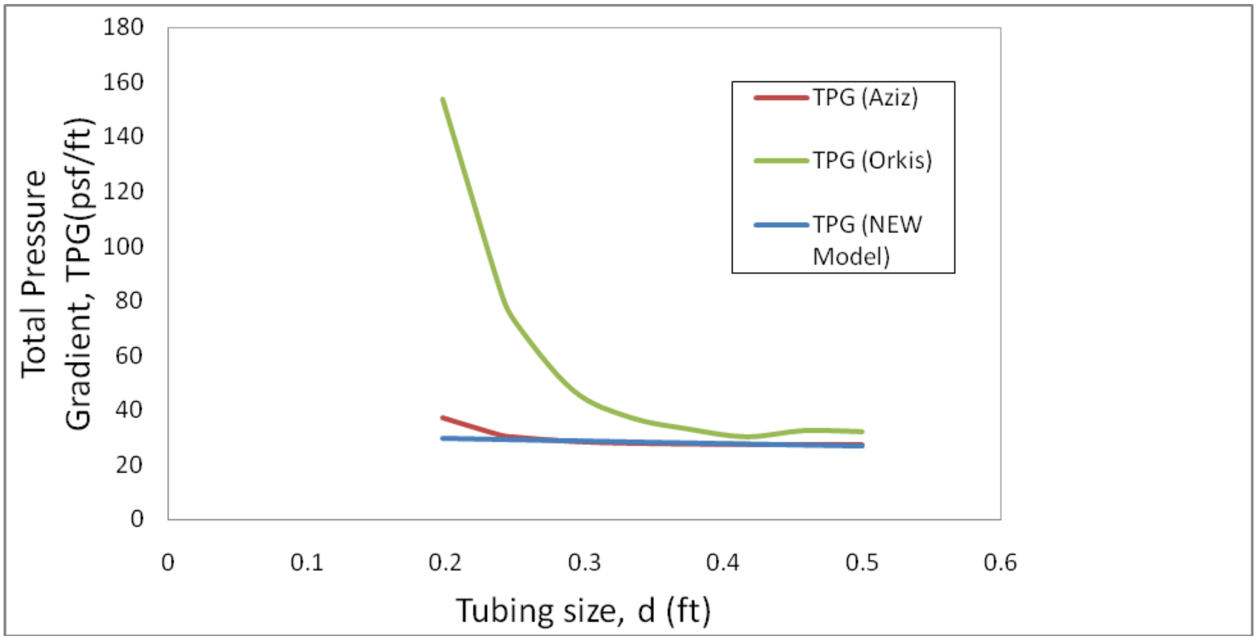

Figure 8: Total pressure gradient (TPG) at different tubing sizes for all models for well 2

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3.5 Pressure profile for different tubing sizes

The total pressure drop and well depth reduces with increase in tubing sizes for all models for well 1 and well 2. The relationship between the total pressure drop and well depth for the new model for diferent tubing is presented in Fig.9 and Fig. 10 showing similar trend.

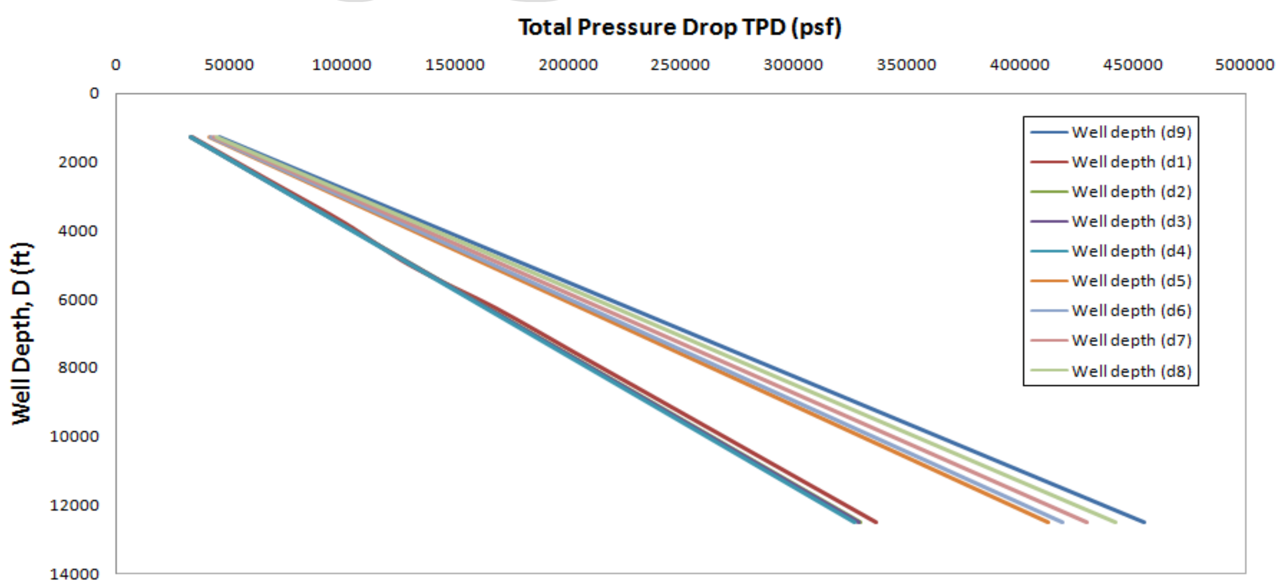

Fig. 9 Total Pressure Drop and well depth at different tubing sizes for well 1 for the new model

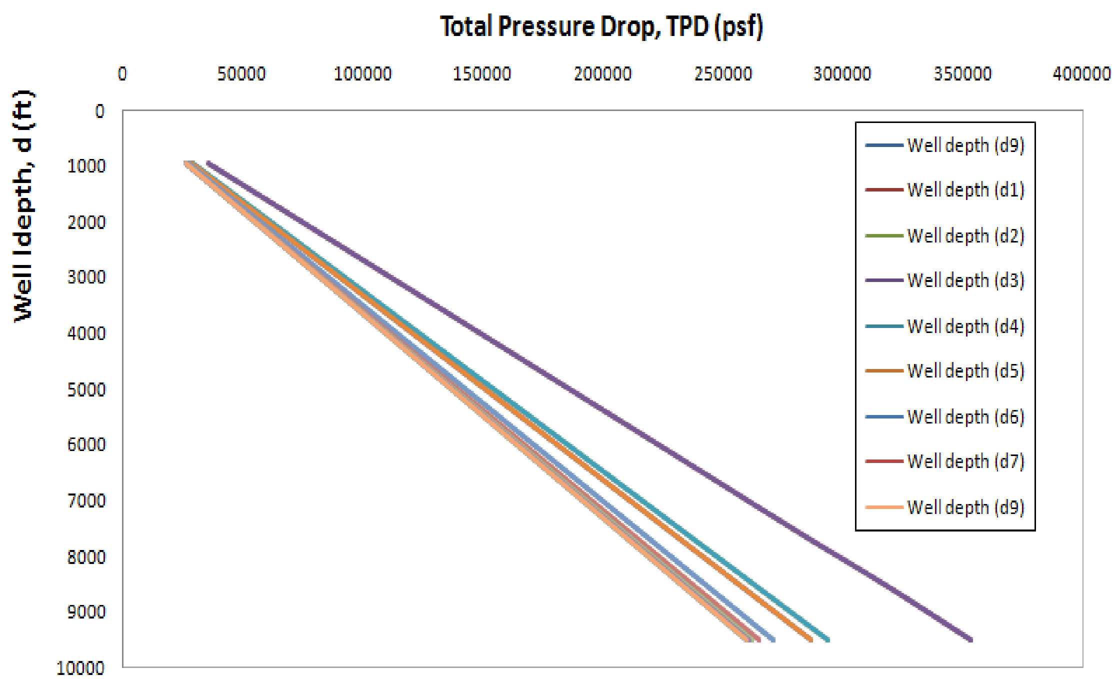

Figure 10 Total Pressure Drop and well depth at different tubing sizes for well 2 for the new model

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4 CONCLUSION

Results of the wells used in this research show that the new model developed for estimating TPG is reliable. Increase in tubing sizes within the range of 2 3/8'' to 6'' decreased the TPG from 31.5335 psf/ft to 28.8763 psf/ft for well 1 and from 29.6212 psf/ft to 27.1251 psf/ft for well 2 indicating better performance than existing models. The new model was selected as the best model by the tool with the lowest TPG of 27.1251 psf/ft and OTS of 6'' for well 2. The OTSP developed predicted 3 ½ '' as the OTS for well 1 and 6'' for well 2. The tool is useful for predicting vertical multiphase flow behavior and will help the production engineer in confirming the result of nodal analysis and selecting the best tubing size that can give the lowest TPG which will maximize production.

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ABBREVIATIONS AND ACRONYMS

OTS – Optimum Tubing Size (inches)
TPG – Total Pressure Gradient (psf/ft)
ρ_{tp} – Two phase density (Ibm/ft^3)
ρ_L – Liquid density (Ibm/ft^3)
ρ_g – Gas density (Ibm/ft^3)
q_L – Liquid flow rate(ft^3/sec)
q_g – Gas flow rate(ft^3/sec)
q_m – Total flow rate(ft^3/sec)
V_m – mixture velocity(ft/sec)
V_{sl} – Superficial velocity of liquid(ft/sec)
V_{sg} – Superficial velocity of gas(ft/sec)
H_L – Liquid holdup
H_g – Gas holdup
d – Tubing size (inches)
g_c – Acceleration due to gravity(ft/sec^2)

APPENDIX

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Table 1: Regression Variables

Variable	Value
A	9.80099383652872E-03
B	0.030869453165894
C	0.424483130391624
D	-0.548564379161516
E	-0.291397747866642
F	2.83435996344733

Table 2: Key Statistical Parameters

Sum of Residuals = -2.52908239211891E-03
Average Residual = -4.59833162203438E-05
Residual Sum of Squares(Absolute) = 12.9325853190865
Residual Sum of Squares(Relative) = 12.9325853190865
Standard Error of the Estimate = 0.513741484245159
Coefficient of Multiple Determination(R^2) = 0.9833170108
Proportion of Variance Explained = 98.33170108
Adjusted Coefficient of Multiple Determination (Ra^2) = 0.9816146649

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Table 3: Range of Dependent and Independent Variables of 100 data points

Variable	**Minimum**	**Maximum**
Total Pressure Gradient(psf/ft)	18.2000	40.5599
Liquid density(Ibm/ft^3)	45.4530	49.6032
Gas density(Ibm/ft^3)	4.5200	10.3586
Liquid flow rate(ft^3/sec)	0.1150	0.9575
Gas flow rate(ft^3/sec)	0.1150	0.9550
Tubing Sizes(inches)	2 3/8	6

Table 4: Range of Applicability of New Model

Variables	**Range**
^{o}API	25 - 45
Solution Gas Oil ratio(Rso)(scf/stb)	280 - 500
Bottom Hole Pressure(psia)	1700 - 3500

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Flowing temperature(^{o}R)	620 - 660
Tubing sizes(inches)	2 3/8 - 6

Table 5: well 1 and well 2 data

WELL	**1**	**WELL**	**2**
Type	**Vertical**	**Type**	**Vertical**
Choke size, inches	32	Choke size, inches	32
WHP, FTP,psig	620	WHP, FTP,psig	625
Liquid Rate, BFPD(ft^3/sec)	2692.7872(0.1750)	Liquid Rate, BFPD(ft^3/sec)	11969.8237(0.7779)
Water Rate, BWPD(ft^3/sec)	31(0.002)	Water Rate, BWPD(ft^3/sec)	250(0.0163)
Oil Rate, BOPD(ft^3/sec)	2662.0125(0.1730)	Oil Rate, BOPD(ft^3/sec)	11719.5037(0.7616)
Gas Rate, MCFD(ft^3/sec)	19.44(0.225)	Gas Rate, MCFD(ft^3/sec)	65.4307(0.7573)
Producing GOR, (scf/stb)	362.500	Producing GOR, (scf/stb)	320.4525
Water Cut, %	18	Water Cut, %	18
API	28	API	40
Gas formation Volume Factor(cuft/scf)	0.0095	Gas formation Volume Factor(cuft/scf)	0.0091
Solution GOR (scf/stb)	320	Solution GOR (scf/stb)	281
Oil Init FVF (rb/stb)	1.20	Oil Init FVF (rb/stb)	1.197
Flowing bottom hole temp (Deg F)	160(620)	Flowing bottom hole temp (Deg F)	180(640)
Current Pressure (psia)	3150	Current Pressure (psia)	1500
Bubble Point Pressure (psia)	3500	Bubble Point Pressure (psia)	1700
Initial Pressure (psia)	3500	Initial Pressure (psia)	1700
Liquid Interfacial tension(dynes/cm)	6.24	Liquid Interfacial tension(dynes/cm)	8.41
Liquid Viscosity(cp)	1.05	Liquid Viscosity(cp)	0.97
Gas Viscosity(cp)	0.0185	Gas Viscosity(cp)	0.0185
Tubing Size (inches)	2 7/8	Tubing Size (inches)	6
Well depth , MD ft	12500	Well depth , MD ft	9500
Well depth, TVD ft	10,575	Well depth, TVD ft	8525
Roughness of pipe	0.0006	Roughness of pipe	0.0006

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